UTAH PUBLIC SERVICE COMMISSION
TRANSMISSION JURISDICTION

Jurisdiction and authority

The state regulatory process governing transmission investment includes planning, construction, and cost recovery in retail rates. The Commission has no siting authority; local governments have jurisdiction over transmission line siting. The Commission is indirectly involved in siting through its membership on the Utility Facility Review Board which has authority to adjudicate transmission facility routing disputes. The following is a general review of state regulatory practice in Utah.

Planning

Transmission additions are considered in the Integrated Resource Planning ("IRP") process in the context of providing long-run, least-cost service to retail customers.[1] Transmission upgrades to better utilize existing generation to meet growing demand may also be considered outside of the IRP process and brought before the Commission on a case by case basis.

Utah acknowledges rather than approves IRP's. Regulatory approval of specific transmission projects identified in the IRP occurs when more is known about the specific generation/transmission project. The basis of the evaluation for a transmission project is the overall cost of the generation/transmission project as compared to other available generation/transmission alternatives.

Transmission planning may also be coordinated with utility distribution planning processes. Additional planning efforts occur in subregional and regional transmission planning organizations. The Northern Tier Transmission Group and the Western Electric Coordinating Council engage in subregional and regional transmission planning respectively.

Construction

For state jurisdictional utilities, i.e., investor-owned utilities like PacifiCorp, doing business in Utah as Rocky Mountain Power, construction of new transmission facilities located in that state requires receipt, after hearing, of a Certificate of Public Convenience and Necessity ("CPCN"). Extension of existing facilities may not require a CPCN but may require notice if the cost is over a specified amount.

Interlocal Entities (i.e., Utah Associated Municipal Power Systems known as UAMPS) or out-of-state public agencies must also obtain a CPCN, after hearing, for new facilities located in Utah; however, if the new facilities provide additional project capacity or

[1] This process is also known as a least-cost or capacity expansion planning process.

provide additional project capacity within the corridor of an existing transmission line, the facilities are exempt from the CPCN requirement.

Applicants for a CPCN must show that public convenience and necessity does or will require such construction and in addition that such construction will in no way impair the public convenience and necessity of electrical consumers of that state at the present time or in the future.

Siting

Siting of new transmission facilities is not under state public service commission jurisdiction but rather is considered and approved by county zoning and planning commissions and then by county commissions, regardless of whether the facilities are proposed by utilities or merchant developers.

Transmission Cost Recovery through Retail Rates

All transmission costs of public utilities, both capital and ongoing, are considered for recovery by state public service commissions in retail rate proceedings. Prudent transmission costs are recovered from customers in the price they pay for service. Merchant transmission costs are recovered through wheeling rates determined by the Federal Energy Regulatory Commission.

Criteria for determining cost recovery

Criteria used to determine public utility transmission investment cost recovery varies.[2] Generally, evaluation of transmission investment is tied closely with prudence review of generation plant additions.

If a state has an IRP process, adherence to its results may form the basis for prudence determination. For example, PacifiCorp engages in a system-wide[3] planning process to determine the optimal investments needed to minimize long-run total cost to operate its integrated utility system. With respect to new generation and transmission facilities, most PacifiCorp states agree the basis for least cost evaluation is system wide, rather than state specific analysis.[4] This is because PacifiCorp operates its system based on minimizing total utility system cost rather than minimizing individual state utility service. Joint-use transmission costs are therefore allocated among states rather than directly assigned to the state in which the facility is located. For distribution and demand-side investments, the PacifiCorp states agree that PacifiCorp will evaluate opportunities based

[2] The following is a general discussion and placeholder for evaluation criteria. Further refinement of criteria employed should be possible with information gained from our review of actual cases in each state.
[3] PacifiCorp serves retail customers in six states and wholesale customers throughout the WECC from its generating resources located in nine states and wholesale purchase contracts and transmission rights located throughout the WECC.
[4] Wyoming, Utah, Oregon, California and Idaho Commissions have adopted the Multi-state Process (MSP) "revised protocol" allocation factors. These five states comprise about 90% of PacifiCorp's retail energy load.

on system cost, through the IRP process; however, state specific programs are developed for, approved by and costs directly assigned to the state in which the investment occurs.

Competitive bidding results may additionally inform transmission investment prudence determination. Indeed, specific alternatives may not be known until competing proposals are solicited and evaluated.

Although most PacifiCorp states support IRP and common allocation factors, costs recovered in each state result from state specific rate proceedings. Thus, evidence and expert opinion regarding prudence can vary in each state and therefore differences in the amount of costs included in rates can still take place.

Rate (Pricing) Treatment

Here are three ways through which prudent transmission cost can be apportioned to customers: Bundled retail cost of service; unbundled transmission service; unbundled retail and wholesale transmission service. A brief description of each follows.

Cost Recovery through Bundled Retail Cost of Service

In this approach, transmission cost of service and wholesale wheeling revenues[5] are combined with other cost of service functions, i.e., generation, distribution and overheads, etc., to form a single retail rate. No distinction is made between wholesale transmission cost of service and retail transmission cost of service. This is how PacifiCorp recovers its transmission costs in Utah.

For example, PacifiCorp reports to states its financial results and operations using FERC's uniform system of accounts. All transmission net plant investment, expenses and wholesale wheeling revenues are included in PacifiCorp's results of operations and are apportioned among the state jurisdictions it serves. A utility's purchase of transmission service from another owner's facilities is included as a wheeling expense in its cost-of-service.

Costs in the transmission-related FERC accounts (gross plant, accumulated depreciation, wholesale wheeling revenues, operation, maintenance and depreciation expenses) are generally allocated among states served by PacifiCorp based on relative loads: 75% weight is given to relative demand based on the sum of 12 monthly coincident peaks and 25% weight is given to relative annual energy use. All states in the PacifiCorp service territory allocate new net plant investment and annual operation and maintenance expenses and firm wholesale wheeling revenues using the 75% demand, 25% energy allocation factors. Non-firm wholesale wheeling revenues are allocated based on relative annual energy use.

[5] Utilities collect revenues from firm and non-firm wholesale transmission customers through contracts or through their Open Access Transmission Tariffs ("OATT"), which are then credited to retail customers, just as wholesale wheeling purchases of transmission service from other utilities through contract or the OATTs are included as expenses in retail rate proceedings.

Under this approach, retail customers bear the risk of any difference in wholesale transmission cost of service and firm wholesale wheeling revenue.

Cost Recovery through Unbundled Transmission Service

This approach requires separating transmission service cost from non-transmission service cost. A fully-distributed transmission service cost analysis is performed and these costs (including only non-firm wholesale wheeling revenues as credits) are used to derive a firm transmission rate based on total use (retail plus wholesale) of the transmission system. This approach is the basis for FERC wholesale wheeling tariffs (OATTs) and a similar approach is also used in Utah for retail recovery of natural gas pipeline cost.

Under this approach, retail customers still bear the risk of any difference in wholesale transmission cost of service and firm wholesale wheeling revenue.

Cost Recovery through Unbundled Retail and Wholesale Transmission Service

This approach also requires separating transmission service cost from non-transmission service cost. A fully-distributed transmission service cost analysis is again performed but now these costs (including only non-firm wholesale wheeling revenues as credits) are allocated to firm retail and wholesale customers based on relative use. Thus, transmission service is further unbundled into retail transmission service and wholesale transmission service. A separate firm retail transmission rate is formed from the retail transmission distributed cost of service study. The retail rate is then multiplied by firm retail use to derive transmission expense and included in retail cost of service.

Under this approach, retail customers no longer bear the risk of any difference between wholesale transmission cost of service and firm wholesale wheeling revenue. This spreading of risk is an important distinction from the previous two approaches because it may be more compatible with non-utility based transmission expansion investment decisions and alternative transmission expansion funding alternatives, i.e., direct assignment or participant funding.